4 Electricity Demand, Supply, and Infrastructure

4.1 Summary Findings

The Regional Energy Infrastructure Study (Study) reports the following key findings for electricity demand, supply and infrastructure:

4.1.1 Short Term 2002–2006

- The San Diego region will continue to be a high-cost electric market at least through 2006.
- Transmission capacity and import capability become important over the 2004–2010 time period. To avoid near-term imbalances the region needs 1 to 2 new generation plants, additional transmission, and increased energy efficiency. If these resources are not available, higher prices and load curtailments may occur.
- Unless the region pursues a strategy of diversifying its electric supply portfolio, including energy efficiency, demand response, distributed generation, renewables and additional transmission, the ability of the region to meet its needs in the longer-term will become increasingly difficult, particularly in the outer years.
- The recent economic downturn, low energy prices, the fallout from the collapse of Enron and the uncertain political and regulatory situation in California has significantly delayed the number of new power plants being built in California and San Diego County. There is high uncertainty surrounding new power plant development in the region.
- For a number of reasons, the region is not an attractive location for new plant development, even though the load growth exists and some new plants have been announced—it is highly uncertain if these plants will be built.
- New CAISO locational marginal pricing (LMP) transmission pricing and capacity reserve requirements for regional grid reliability suggest that the region is going to be more vulnerable to system constraints unless additional generation and transmission is added to the area.[1]
- A number of needed transmission improvements are being made in the region. Because of reliability concerns and the fact that the region has only one major northern feeder into the region, it appears that additional transmission to the North is necessary. The line will be needed by 2005 unless the region takes positive action soon to ensure new generation or other alternatives are in place by that time.
- A broader regional energy infrastructure plan is needed. Currently, the planning of infrastructure project initiatives is too fragmented. Additionally, energy infrastructure planning should be a transparent process that is more accessible to the public.
- Load flow analysis is needed to evaluate the most optimal way to balance new transmission development and co-location of generation, not only for supply purposes but also for regional grid reliability.
- An energy development authority needs to track demand and renewable resources along with transmission as a basis of considering additional generation.
- In somewhat of a rebuttal to the findings of this report, SDG&E reports that the newly negotiated CDWR contracts coupled with SDG&E's generation and long-term power purchases substantially meets all of the region's energy needs, states SDG&E.[2] However, no evidence or even documentation was provided to reinforce this opinion. As part of the strategy development task, SDG&E and SDREO should work to verify this assertion.

[1] SDG&E commented in its evaluation of the draft REIS that LMP pricing of the capacity reserve requirements is not going to increase vulnerability over what it is now.
[2] From the draft to the final report, CDWR and the CPUC negotiated the capacity and cost allocations to the state's three investor-owned utilities. When the local energy strategy is being developed, careful evaluation of these contracts is needed. they can have a major impact on local resource economics, reliability, and equity.

4.1.2 Mid Term 2006–2010

- Additional transmission to the north will be needed. At least one in region generation plant will also be needed.
- A much stronger contribution of DG and renewable energy resources is expected in this time frame.

4.1.3 Long Term Post 2010

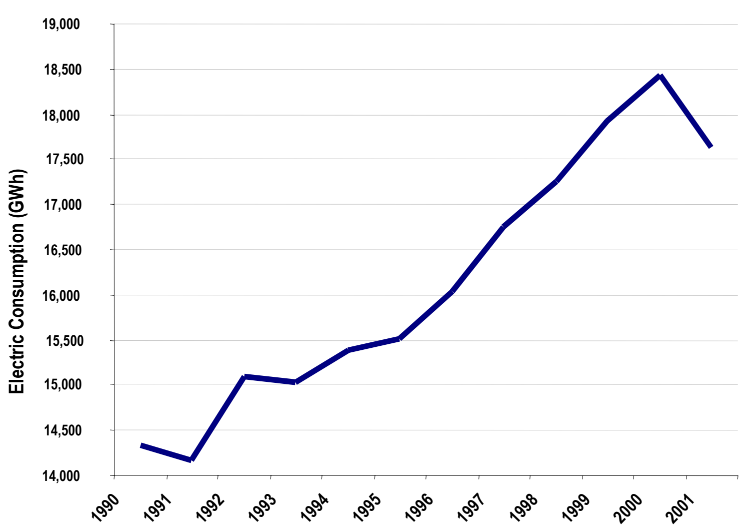
- Substantial renewable resource imports are expected from eastern San Diego County and North Baja
- One-to-two additional power plants may be needed – with one each in the 2010 and post 2020 time period.
- The region should seriously consider an additional transmission line to Arizona for access to new capacity that is expected to be built there.

4.2 Electricity Demand and Consumption Trends and Forecasts

4.2.1 Historical Energy Consumption

Figure 4-1 presents the historical annual energy consumption for the San Diego region during the 1990–2001 period. The San Diego region consumed 17,632 gigawatt-hours[3] (GWh) in 2001, down 4.3 percent from 2000.

Figure 4-1: Electricity Consumption (GWh)



Source: SDG&E

This decrease in consumption was the result of the impact of higher prices, consumer conservation behavior and other factors such as increased use of small-scale, distributed generation. Historically, electricity consumption has grown an average of 3.1 percent per year. Peak demand for 2001 was about 3,200 MWs, down 18 percent from 2000[4], which represented the largest 1-year decline in demand in the last 50 years.[5] Between 1988 and 2000, peak electric demand grew an average of 3.4 percent per year. Demand forecasts in recent years are lower than in the past for several reasons, including a more pessimistic economic outlook, higher electric rates, new conservation programs, long-term impacts of state-sponsored conservation efforts and new appliance efficiency standards.[6] These estimates are likely conservative, as historical demand forecasts by SDG&E and the CEC have tended to under forecast demand by between 4 percent (during economic recession periods, like the early 1990s) and 21 percent (as was the case during the high economic growth during the late 1990s).[7] Since the last forecasts accomplished by SDG&E in October 2001, electricity usage has rebounded significantly and it is expected that shorter-

[3] Approximately 6 percent of SDG&E's electricity demand is located in southern Orange County.
[4] SDG&E.
[5] SDG&E.
[6] SDG&E rebuttal testimony in Valley-Rainbow case.
[7] SDG&E rebuttal testimony in Valley-Rainbow case.

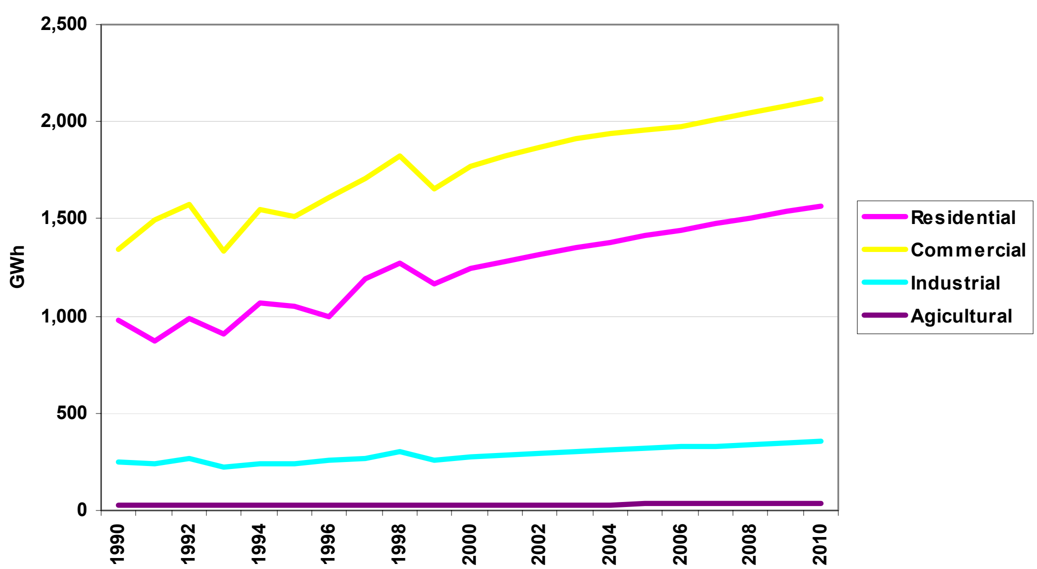
term forecasts are indeed low, having been overly influenced by the extraordinary conservation efforts of 2001.[8]

Demand for electricity is influenced by various economic and non-economic factors, and it is difficult to isolate the magnitude and timing of contribution by any one factor. All major energy related events, pronounced trends in economic conditions, temperature and change in consumers' energy consumption behaviors, introduce a great deal of uncertainty in long-range load forecasts.

4.2.2 Per Capita Electricity Growth and Energy Intensity

Long-term electricity use trends are driven by many factors, the most significant being economic, population, commercial building and new housing. While population and housing growth has slowed from the 1980s to the 1990s by more than 60 percent, electricity demand growth has slowed by only 40 percent. This is due to a slight increase in per capita consumption over the longer-term. More electricity is being consumed per person in San Diego despite significant conservation efforts and advancements in technologies. The increased consumption per person is likely due to several factors, including the increase in use of computer electronics, building larger homes and more homes that are inland, which require air-conditioning. The most influential factors driving short-term electricity demand is the economy and the increased use of air-conditioning.

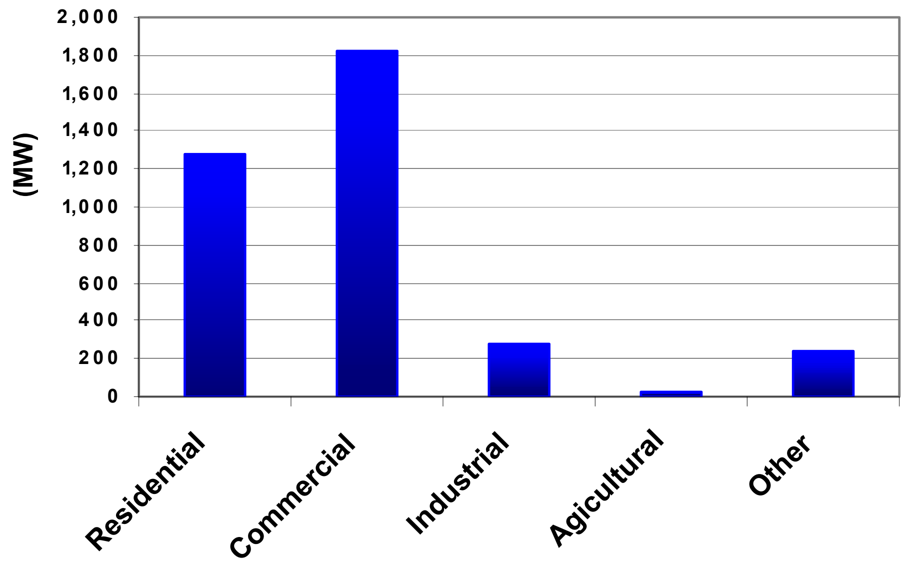
Figure 4-2 shows historical and projected electricity consumption by sector for the 1980–2010 period. The data show higher growth rates for the commercial segment, followed by residential. Flatter growth is shown for industrial, agricultural and other sales. For the year 2001, the relative shares in peak demand by sector, appear in Figure 4-3. The commercial market has the largest share of electric use (49 percent) followed by residential (35 percent). All other uses together total 19 percent.



Source: SDG&E

[8] SDG&E, Opening Brief of San Diego Gas & Electric Company (U 902-E) on the Need for The Valley-Rainbow Interconnect Project, July 12, 2002.

Figure 4-3: Peak Electricity Demand by Sector (MW)



Source: SDG&E

4.3 Electricity Supply: Generation and Transmission

4.3.1 Existing Generation Stock in San Diego County

Generation plants vary in size depending on their application and intended use. Currently, San Diego has a total on-system generation capacity of about 2,359 MWs, about 55 percent of the region's summer peak demand. This capacity consists of 1,628-MW base-load plants. The remaining capacities are small and medium-sized peaking plants and on-site generators (excluding backup generation). All of this generation is not normally available since many of the generators are for emergency use and not available when needed. Available in County generation during peak period is approximately 64 percent of the region's peak demand. A complete listing of all power plants located in San Diego larger than 100 kW can be found in Appendix F.

Cancellations of power plant proposals have become common.[9] In light of this high degree of uncertainty, SDG&E is forced to plan for grid reliability improvements based on very conservative generation expansion assumptions because the utility must provide reliable service regardless of the uncertainties of the regulatory climate and capital markets for generation investment.[10]

San Diego County has two major steam electric generating units and a number of smaller combustion turbine units, most of which were constructed between 1960 and 1978. Although these units have continued operation with modifications and upgrades, they are quickly nearing technological and economical obsolescence. A number of the least-efficient, must-run units have in the past operated at capacity factors in the 3 percent range and are needed to perform must-run duty 5 percent of the year.[11] Must-run units are more expensive to operate and are only used as operating reserves during

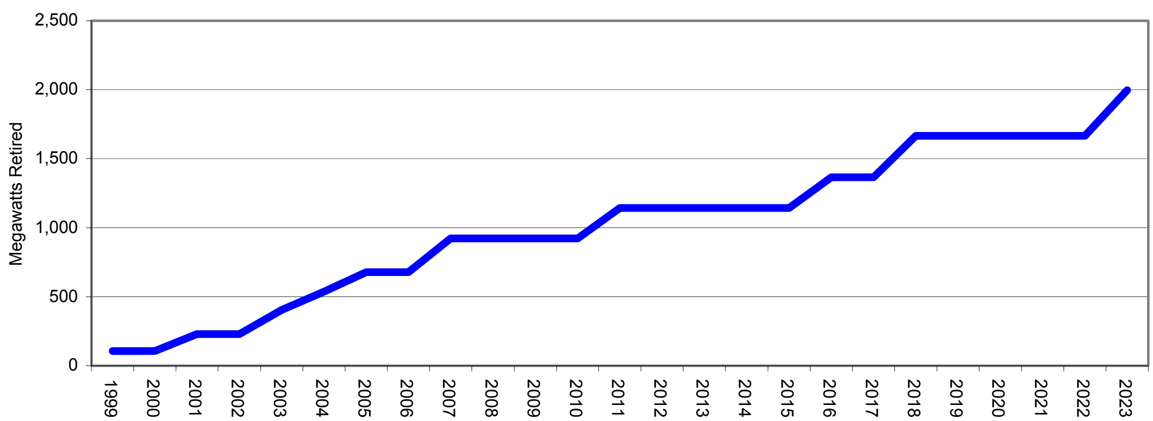
[9] Exh. 101 (at p. 5). This appeared in the Valley Rainbow filing.
[10] Exh. 5 (at p. II-16).
[11] Analysis of San Diego Gas and Electric Company's Marginal Cost and Rate Design, Prepared Testimony of William B. Marcus, JBS Energy, Inc., on behalf of Utility Consumers Action Network, March 1, 2000.

peak periods or in times of emergency backup. This is because the outage costs are much higher than the power generating cost.[12]

The Cabrillo Power Plant[13] in Carlsbad, owned jointly by NRG and Dynegy, has a capacity of 965 MWs. The South Bay Power Plant,[14] located in Chula Vista is owned by the Port of San Diego, and operated by Duke Energy, has a capacity of 690 MWs. The design-life of the combustion turbines in San Diego County is approximately 35 years. Fossil-fired steam units such as South Bay and Cabrillo are designed to operate 40 to 50 years. Although many units outlive their design life, forced outage rates increase with time, leading to a higher likelihood that they will not be available when needed. This is why the County needs additional supply reserves that may be used should a major plant be taken out of service. These reserves can be provided by either in-region power plants or through existing or new transmission. CAISO grid reliability criterion requires that the system be able to serve the load even after the loss of the largest transmission line and the single largest generator. The load forecast used for analysis is based on a forecasted load that has only a 10% probability of being exceeded. Sufficient reserves are needed in the region to meet this situation. Some units may be retired or not operate due to economic or environmental issues, such as limitations on operating hours due to emissions. Therefore, the retirement of a significant amount (i.e., greater than 1,500 MWs) of the existing generation stock currently existing in San Diego County in the next 15 years could be expected. This planning assumption is reflected in the high growth scenario that is presented in Chapter 6.

Figure 4-4 presents the annual projected cumulative retirements of generating units in San Diego County. An estimated 67 MWs of older combustion turbine units are estimated to be removed from the region by 2003 because these plants are old, inefficient and beyond their useful economic life. All remaining units are RMR must run units.

Figure 4-4: Projected Cumulative Retirements of Generating Units in San Diego County[15]



Based on currently available generation technology, plants such as South Bay or Cabrillo can be re-powered and double or nearly triple their current capacity without increasing NOx.[16] Additional potential benefits include increased local tax base, improved water use efficiency of up to 50-percent reduction per MW, improved visual attributes due to a smaller plant infrastructure and the creation of needed emission offsets to build additional capacity. The repowering or replacement of the South Bay Plant may allow for a dry cooling configuration, which would reduce its impacts on the San Diego Bay.

[12] SDG&E adds that must run units are also needed to overcome transmission constraints and CAISO load balancing requirements. The lack of transmission in the region has led to a substantial number of must run units being located in the region.

[13] The 5 Cabrillo Power Plant Units were placed in service 1954 (Unit 1), 1956 (Unit 2), 1958 (Unit 3), 1973 (Unit 4) and 1978 (Unit 5).

[14] The 4 South Bay Power Plant Units were placed in service in 1960 (Unit 1), 1962 (Unit 2), 1964 (Unit 3) and 1971 (Unit 4).

[15] California Energy Commission, 2001 Database of California Power Plants.

[16] Additional NO_X reductions have occurred at the South Bay Plan and, in the near term, additional reductions are planned at the Cabrillo Plant.

Additionally, air emission credits will need to be obtained since the air emission credits associated with the plant are owned by Duke Energy.

In the case of the South Bay Power Plant, should the replacement plant be constructed at a new site that is not in the vicinity of the existing site, costs to modify and/or move existing transmission infrastructure and to provide needed voltage support in the South County could well exceed $75 million. The additional costs that would be associated with the siting decision are the subject of an ongoing proceeding of the Port of San Diego.

San Diego County's two existing steam-generating stations, Cabrillo (939 MW) and South Bay (690 MW) are approaching economic obsolescence. The Port of San Diego has made a commitment to replace South Bay with a new power plant by 2009. Duke Energy, under the terms and conditions of its existing agreement with the Port, is obligated to use commercially reasonable efforts to develop, finance, construct, and place into operation a new off-site replacement generation plant by 2009. Duke is currently conducting feasibility studies and siting activities for off-site facilities and has identified one potential north county site.

The City of Chula Vista in 2001 voted to recommend that Duke and the Port consider locating the new replacement plant on Chula Vista tidelands. On June 26, 2002 the Board of Port Commissioner's voted to recommend that Port staff and Duke consider replacing the SBPP on the former 33-acre LNG site.

Upon termination of the operation of the SBPP, Duke is to begin performance of the decommissioning obligations that would return the 116 acre site to the Port provided the parties have received approval of the CAISO to commence decommissioning activities.

The Cabrillo Power Plant has had several emission controls improvements made to comply with air quality regulations, which has reduced its emissions by more than 50 percent.[17] Without significant upgrades it is anticipated that both units will be shut down by the end of the decade. Until new combined cycle capacity is constructed in the region, these units will likely continue to be classified as must-run by the CAISO.[18]

SDG&E retains a 20-percent ownership of the San Onofre Nuclear Generating Station (SONGS), which is licensed to operate through 2022. The plant may be able to extend the license another 20 years if the plant's owners apply to the Nuclear Regulatory Commission (NRC) for an extension of the license. If the plant life is extended, the potential costs to upgrade the plant to keep it running may be prohibitive. Unit 1 was shutdown in 1992 after 25 years of operation because the costs to upgrade the unit to current seismic standards and complete needed replacement of critical systems made the continued operation of the plant uneconomic.[19] The remaining SONGS units operate under an "Incremental Cost Incentive Pricing (ICIP)" mechanism, which covers operational costs through December 31, 2003. After this time, SONGS will need to recover its costs in the market. To the extent that the market fails to cover the costs, a decision may be made to shutdown SONGS.[20] A study was completed by the CAISO working with SCE and SDG&E to determine what would happen to the system if SONGS were to shut down after 2003. That study was not available to the authors of this Study. As a result of the failure of industry restructuring, SCE and SDG&E were ordered to operate SONGS for the benefit of ratepayers after 2003. Pursuant to that requirement, SCE's General Rate Case (currently before the CPUC) and SDG&E's Cost of Service case (to be filed later this year) will ask the CPUC to return SONGS to traditional cost-of-service rate making beginning in 2004. This will replace the ICIP agreement relative the post-2003 time frame, and should ensure that the plant continues to operate at least for the foreseeable future.[21]

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[17] San Diego Air Pollution Control District.
[18] CAISO must-run designation is required to ensure these plants are available for local reliability.
[19] Unit 1 was a first generation Westinghouse design, while Units 2 and 3 are Combustion Engineering, Inc. designs. http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/reactors/sanonofre.html.
[20] Attachment A of the San Onofre Nuclear Generating Station Operational Study Phase-2 Report Transmission Plan-of-Service, June 2000.
[21] SDG&E.

If and when the remaining SONGS units are shut down, replacement generation plants equal to its capacity will need to be built in Southern California to provide for system stability. The total capacity that would need to be replaced is equivalent to that of three to four typical combined cycle plants being built today. Therefore, the loss of this generation capacity will be significant in terms of available supply and system stability. If it has not yet been completed, an evaluation of the costs of extending SONGS' life should be completed by SCE and SDG&E in order to begin planning for replacing this capacity if the plants do not continue to operate.

SDG&E also retains long-term purchase power contracts with Portland General Electric for about 85 MWs delivered at the California – Oregon Border ("COB") (which enters SDG&E's system via Path 44 – the South of SONGS path) and Yuma Cogeneration Associates for 57 MWs delivered at North Gila Substation in Arizona (which enters SDG&E's system via the 500-kV Southwest Power Link). All of these contracts are scheduled into SDG&E as imports over the ISO controlled grid and enter SDG&E's service area at SONGS and Miguel.[22]

4.3.2 New Generation Infrastructure

The first key issue facing California is the evaluation of whether or not there is significant new capacity being built and that it is available to meet future demand. The second key issue is whether or not this new capacity can be delivered to San Diego County and within the San Diego region. As the CEC noted in its 2002–2012 Electricity Outlook report, future load growth and generation supply are extremely uncertain, largely due to economic growth, weather and a tightening of the financial markets.

For the short-term, according to the CAISO, operating margins for the 2002 summer season are significantly higher than recent years. Barring extreme weather conditions and/or major generation or transmission outages, the CAISO anticipates there will be adequate resources available to meet the most likely operating scenario for forecasted 2002 summer peak demand and meet minimum operating reserve requirements.23 In addition, the CAISO anticipates that the transmission system will demonstrate adequate reliability performance during peak demand periods.24

The WECC noted in its 2001–2002 annual report that 10,000 MW of new capacity was added in 2001. About sixty percent were combined cycle gas units. A total of 81,000 MW of new generation projects have been identified, of which, 28 % are either in testing or under construction. Over 40,000 MW are estimated to be identified in the California/Mexico region. SAIC has completed a careful analysis of the WECC market and recently completed a new price forecast and model analysis. The Palo Verde region is going to be a large trading and generation location hub and North Baja could become a similar generation hub. This suggests that adequate transmission must be available in order to take advantage of this power.

For this reason, the region needs options it can exercise when supply provided by the market is uncertain. In this short timeframe, options are limited, but available. These options will be discussed in Chapters 5 and 6.

In 2001 and 2002 a total of 325 MWs of new CT were added. Table 4-1 lists the combustion turbines that became operational during 2001. These additions represent almost 2 years of load growth in the region.

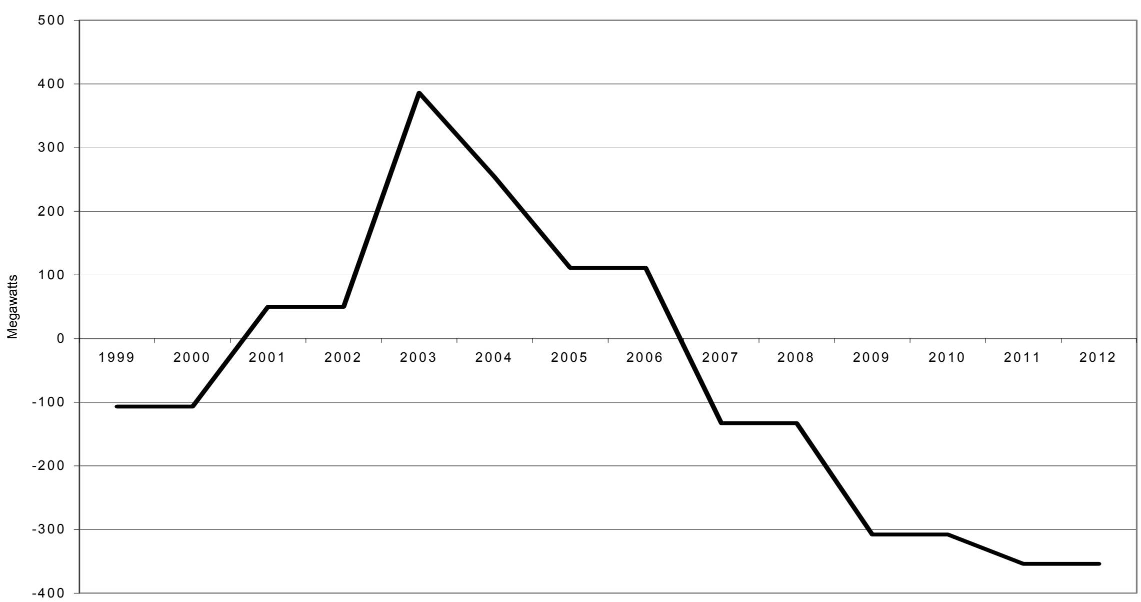
[22] SDG&E.
[23] Which is not to say there will not be electrical emergencies and possible rolling blackouts, as was the case on July 10, 2002 when the CAISO declared the years first Stage 2 and Stage 3 emergencies. During a stage 3 emergency, http://www.caiso.com/docs/2002/07/11/200207111300478205.pdf.
[24] California ISO 2002 Summer Assessment, Version 1.1, May 15, 2002.

Table 4-1: New Generating Units Entering Service in 2001

Project Name	Developer	Maximum MW	Primary Fuel	Technology	Online Date
Lakespur	InterGen NA	90	Natural Gas	CT	7/2001
Chula Vista	RAMCO	42	Natural Gas	CT	7/2001
CalPeak Enterprise	CalPeak	49	Natural Gas	CT	9/2001
CalPeak Border	CalPeak	49	Natural Gas	CT	9/2001
CalPeak El Cajon	CalPeak	49	Natural Gas	CT	5/2002
Escondido Peaker	RAMCO	46	Natural Gas	CT	11/2001
Total		**280**			

While one large power plant is awaiting construction (Otay Mesa) and several plants are in the planning stages, all existing large non-nuclear generation plants will be retired by 2015 (or sooner), therefore, more than 1,600 MWs of generation will be required just to replace existing generation resources. Figure 4-5 illustrates the net additions to the San Diego County generation portfolio versus the retirements, based upon terminal retirement dates. As noted earlier, the state feels that there is sufficient capacity for 2002–2003 to meet peak load requirements. The supply deficit becomes more serious in 2004–2006. For this reason, the region needs to carefully evaluate the additional risks if the Otay Mesa Power Plant is not operational by 2004 along with additional transmission interconnection. Equally or even more important will be the degree to which the region implements more energy efficiency and distributed generation to mitigate or delay the need for this infrastructure.

Figure 4-5: Projected Cumulative Net Additions and Retirements of Generating Units in San Diego County[25]



Many merchant developers of generating units have experienced financial crises recently. Calpine, a major developer of plants in California has announced a retrenchment in their development efforts. NRG/Dynegy, the owner of the Cabrillo Power Plant, has recently announced its parent corporation, Excel Energy, will purchase all outstanding equity. AES, another major developer, has also announced a significant reduction in capital spending and new development efforts. This leads to the conclusion that some projects that were announced in the last 2 years may not be completed.

[25] California Energy Commission, 2001 Database of California Power Plants.

The reasons many of these projects will be cancelled include the following:

- Recent wholesale prices have been depressed due to the slow economy, improved hydro conditions and the addition of new plants in the region. These conditions have alleviated the price spikes that occurred last year and thus reduced the incentive to construct new assets.
- Many of the developers of merchant generation have experienced deteriorating financial conditions due to the fallout of the Enron and corporate accounting debacles.
- The State of California is in the process of renegotiating purchased power agreements signed last year creating price uncertainty for developers.

4.4 San Diego County's Electric Power Market

San Diego County is not an attractive location for locating new power plants due to the lack of suitable sites away from populous areas, which results in increased costs and delays due to environmental concerns. Some of constraints of building new power plants are presented in Table 4-2.

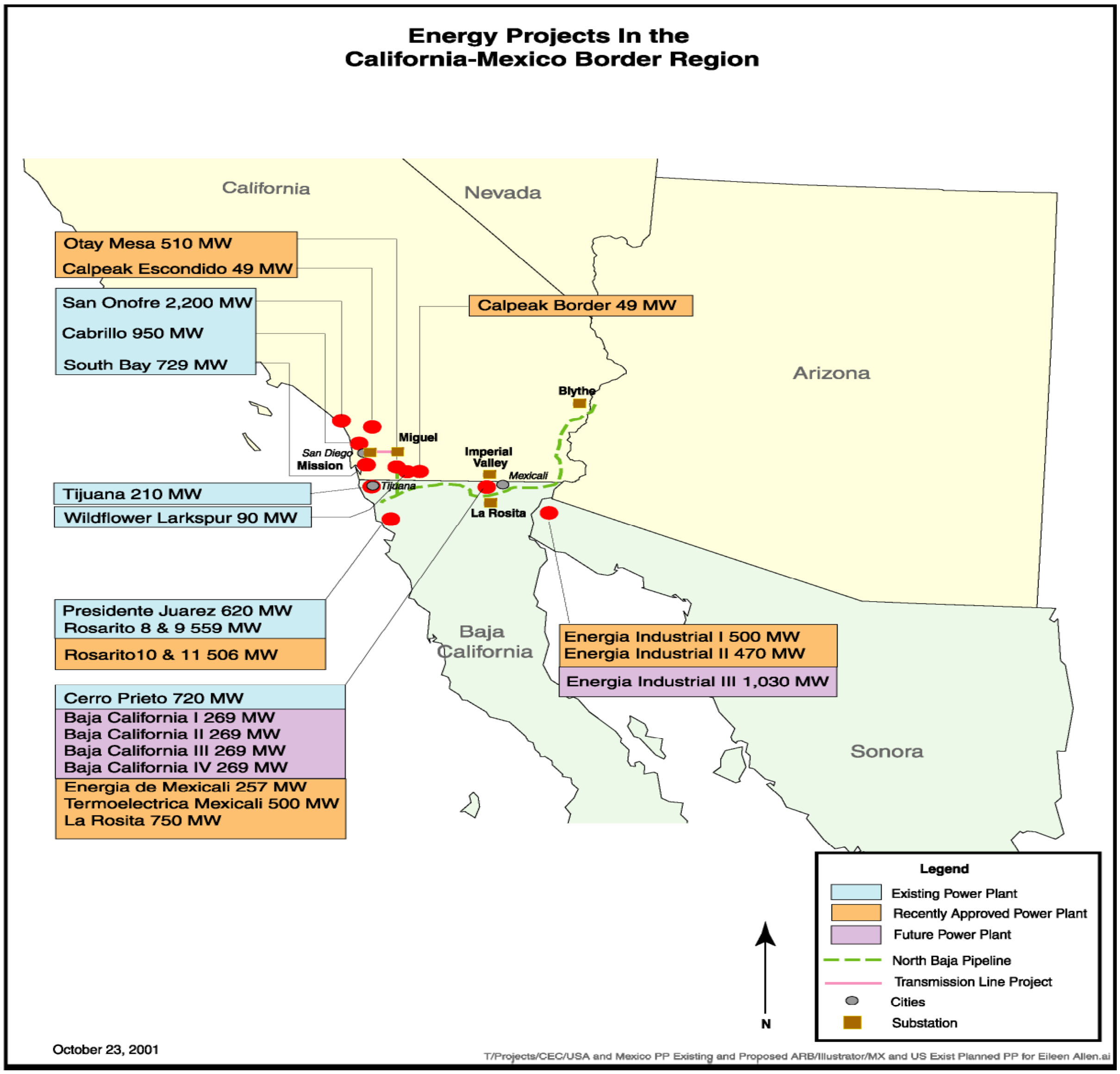
Table 4-2. Constraints in Building New Power Plants in Southern California

Attribute	Comment
Availability and Cost of Water	Southern California and San Diego currently suffers from severe shortage of water. The relative cost of this commodity compared to other regions in the WSCC is high.
Availability and Cost of Coal	San Diego has no potential for the development lower-cost coal-fired generation. This technology requires a significant amount of water, a large site, and significant rail access for unit trains of coal. Furthermore, coal emits much higher levels of SO_X and NOx and San Diego is distant from inexpensive sources of coal.
Availability and Cost of Natural Gas	San Diego has the most expensive natural gas in the WSCC.[26] The state's two main gas supply basins are the Permian Basin and the San Juan Basin. The El Paso Pipeline Company does have major pipeline facilities tied to these basins. Inasmuch as this pipeline provides low cost natural gas in the Southwest, the cost to transport natural gas from the California border to San Diego is relatively high.
Regional Cost Levels	San Diego is a high-cost region to both construct and operate generating assets. In addition to the normal issues associated with regional cost differentials of electric generation, units in California must be able to generate electricity while emitting much lower levels of NOx and simultaneously using less water. Additionally, the financial community currently views California, in general, as an unfavorable investment climate for new plants due to the current CDWR long-term power contract commitments and regulatory uncertainty.
Availability of Suitable Generation Sites	There are very few suitable generating sites in San Diego given the limited amount of suitably zoned land. Coastal land is considered premium property and tends to be congested. Sites are generally limited to those near the intersection of natural gas supply and transmission access.
Cost to Transmit Power to Load Center	This is the one area where San Diego excels. This region is a major load center with relatively little indigenous generation resources.

[26] SDG&E reports that transport gas from the California border is $.20 of a total $3.00/MMBTU cost.

A substantial number of new power plants and energy infrastructure projects are planned for the region. Figure 4-6 depicts the approximately 4,000 MWs of new plants expected between 2002 and 2004 in the California border region. Most of the new plants being added during 2001 and 2002 are combustion turbines, which dispatch at approximately $45/MWh. The annual capital cost of these units is $65/kW-yr. The average heat rate of these units is approximately 12,500 BTU/kWh; nearly 50 percent more inefficient than state-of-the-art combined cycle plants.[27] The average unit cost for these plants is about double what the current market price is for power on the open market and the capital cost is close to the price point where significant numbers of consumers will participate in demand response programs (assuming that $75/Kw-yr is a price threshold where a significant proportion of the market is willing to participate).

Figure 4-6. Projected New Plant Development In the San Diego Region



[27] This study does not use a manufacturer's heat rate but one that assumes ramp up, ambient temperatures, humidity and other operating conditions that can lower heat rates.

Units planned for 2004 are more speculative. Imports, long-term CDWR contracts and regional WECC prices may influence the use of these plants in the region.[28] San Diego County will have to compete with plant development costs in other regions and also have to secure power contracts to mitigate the investment risk of the units.

Power plants under construction in Baja California appear to have a higher probability of being completed than new plants in San Diego County, due to lower cost of construction, greater political and regulatory support and less rigorous environmental requirements. While planned new generation capacity in Baja California is close to 1,900 MWs, much of this supply is intended to meet the growing needs of Mexico. The actual transmission capacity back across the U.S. border from Baja Norte into California is 800 MWs. There are approximately 500 MWs of potential transmission capacity additions being studied for power delivery from Baja California to California. However, while this capacity may increase supplies that could have an economic benefit, they do not necessarily improve reliability, since all the power would be imported through the Miguel Substation.[29]

4.4.1 The Need for New Power Plants

Increasing in-region electricity production is paramount to the regional goal of cost-effective and reliable energy supply. The only baseload generation projects anticipated for construction in the near future are the replacement of South Bay Power Plant, Calpine Energy's Otay Mesa facility and possibly one or two other plants, including the proposed Sempra Energy Plant in Escondido and a proposed plant in the City of San Diego. The Otay Mesa Power Plant completed its certification process in 2001 and is awaiting secured financing by Calpine Energy. The plant is to be built on a 15-acre site in San Diego County, about 1.5 miles north of the U.S./Mexico border.[30]

This facility is proposed to be a $300-million, 510-MW combined cycle plant. Although recent CDWR contract renegotiations with Calpine required "commercially reasonable efforts" for Otay Mesa to be on-line by December 31, 2004, there is no firm requirement that the plant be operational by this date. Calpine has a wide range of resources to draw upon to fulfill its contractual obligation to the State so it does not need to build Otay Mesa to fulfill this obligation. Moreover, Calpine's obligation in the contract to use "commercially reasonable efforts" to construct Otay Mesa only means that Calpine will build Otay Mesa if it is profitable for Calpine to do so. There are provisions that would allow the State to step-in and build the power plant if necessary, however, whoever builds the Otay Mesa Plant, would need to contract for its output. This contracting would compete with existing CDWR power purchase contracts and may force SDG&E to sell power from existing CDWR contracts into the market at discounted rates.[31] Thus, there is still significant uncertainty regarding if and when this plant will be built and operational. Additional information regarding the proposed Otay Mesa Power Plant can be found in Appendix D.

SDG&E has stated that a major question regarding Otay Mesa is that limited output from that unit will be needed because existing CDWR contracts satisfy the vast majority of its "net short requirements." As such, SDG&E would be "in a situation of having capacity that is above and beyond the needs of San Diego, and the capacity would do nothing more than displace an existing generating unit."[32] Moreover, SDG&E notes that the renegotiated contract states that the "Delivery Point" for Calpine's 1,000-MW obligation is "Any point or points designated by Seller on North Path 15, except as the Parties may otherwise agree," but these scheduling points are remote from SDG&E's service area. This is yet another factor that weighs against Calpine going forward with Otay Mesa. It should also be noted that CDWR's ability to enter into a new supply contract to serve utility loads ends as of December 31, 2002.

[28] Except Otay Mesa.
[29] The California Independent System Operator (CAISO) is responsible for reliable operation of the transmission grid consistent with of planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC).
[30] http://www.energy.ca.gov/sitingcases/otaymesa/index.html
[31] Conversation with SDG&E staff, July 2002.
[32] SDG&E Valley-Rainbow Testimony to the CPUC, July 2002. However, if new, more efficient generation were added, it may offset an older inefficient unit and also postpone the development of a new unit that is not as far along in the permitting and project development process.

Two additional large-scale, baseload power plants that have been announced include a 500-MW plant in Escondido by Sempra Energy, and a 750-MW plant in eastern San Diego by ENPEX.[33]

4.4.2 Repowering Existing Power Plants

Repowering Cabrillo Power Plant may include the following:

- Replacing the existing units to simple cycle or combined cycle gas units, which includes adding a gas turbine and in the case of a combined cycle unit a Heat Recovery Steam Generator (HRSG). The existing steam turbines may be used or replaced.[34]
- A 10-percent or greater improvement in plant efficiency can occur.
- Repowered stations also include advanced emission control technology. Three of five boilers at Cabrillo are currently equipped with selective catalytic reduction (SCR). The remaining two boilers will be equipped with SCRs by the end of 2003.

4.4.3 New Power Plants in Baja California

There are three major power plants being built in Baja California, including the 750-MW Intergen plant (the La Rosita Power Project or LRPP), the 310-MW La Rosita Expansion Project ("LREP") and the 600-MW Sempra Energy Resources plant in Mexicali (Mexico), which still leaves a substantial amount of proposed generation that may not be built.

4.5 Electricity Transmission

4.5.1 The Role of Transmission and Advantages and Disadvantages

The second means to provide electricity supply to the region is through high-voltage transmission interconnection to broader energy markets. The State Legislature declared that "it is in the public interest to reconfigure and add transfer and replacement capacity to electric transmission facilities to facilitate competition in electric generation markets, ensure open, nondiscriminatory access to all buyers and sellers of electricity, to assure all buyers and sellers of electricity that they will receive comparable service, and to ensure continued reliability of the transmission grid."[35]

The transmission grid provides for a number of functions. These functions include:

- Support wholesale market transactions and help stabilize electric prices
- Improve system reliability
- Create opportunities to site new electric generation
- Improve system stability and reliability
- Provide additional voltage support.

The chief advantages of adding new transmission are:

- Its ability to provide more access to diversified and potentially less expensive plants as opposed to building plants in San Diego County;
- Increase the number of sites where new generation units could be sited in San Diego County;
- Increase reliability though the addition of a new intertie;
- Increase fuel diversity by increasing the markets that San Diego County has access.

The disadvantages of new transmission are:

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[33] ENPEX Corporation, located in San Diego, California, is a privately held owner and developer of energy related projects. It has joint ventured with major international energy corporations on a wide range of projects including oil and gas exploration and production, cogeneration and electric power generating projects and the development of advanced technology.

[34] See "Repowering of Existing Power Station." http://www.mhi.co.jp/pwer/e_power/product/boiler/repowering/

[35] Subsection (k)(1) and (k)(2) of Section 1 of Senate Bill ("SB") 1388.

- New transmission is potentially very costly;
- Siting issues for new transmission lines are often complex due to the large number of parties that are affected by such projects (e.g. visual impacts, potential impacts on property values, concerns for the impacts of electric and magnetic fields (EMF))[36].
- This capital cost is taxed for 30 or more years.

The taxing of new transmission is also viewed as a potential benefit to local governments where the line may pass through. Taxes will also apply to new generation stations. On an equivalent capacity cost basis (e.g., such as for a combined cycle gas turbine) new transmission is more costly than generation. However, combined cycle units using natural gas run the risk of price volatility. When one considers the reliability value and potential benefits in stabilizing prices and also comparisons to more expensive forms of generation and supply, transmission additions and upgrades can be very attractive. Increasingly, in congested areas like New York City or Seattle, distributed resources may be attractive alternatives to transmission upgrades, especially if the transmission is routed through dense corridors and in areas of aesthetic value. This suggests that resource investments do involve trade-offs and options. On some occasions, a broader portfolio perspective should be considered in evaluating different investment levels in resource options.

Currently, there are only two points of interconnection today between SDG&E's service area and the external grid. These points are at the San Onofre Nuclear Generating Station ("SONGS") switchyard in the northwest and the Miguel Substation in the south. The SONGS switchyard owns the north half of the switchyard and the four 230 kV lines to its service area. These four SCE lines comprise what is known as WSCC Path 43, or the "north of SONGS path." SDG&E owns the south half of the switchyard and the 230 kV lines to its service area. These five SDG&E lines comprise what is known as WSCC Path 44, or the "south of SONGS path." The Miguel Substation serves as the western terminus of SDG&E's 500kV Southwest Power Link ("SWPL") as well as the northern terminus of a 230 kV interconnection with Comision Federal de Electricidad's ("CFE") Tijuana Substation in Mexico. The Mexico CFE system is not expected to have surplus resources for supplying the San Diego area during the period studied, so the CFE system was assumed to have balanced load and resources. This assumption for CFE resulted in that system having no effect on the San Diego Reliability Must-Run (RMR)[37] Study results. Historically, San Diego County has relied upon imports of electric power to meet about one half of the supply needs of the region (a higher percentage during the summer months, lower during the winter). SDG&E has an effective transmission import capability of 2,850 MWs south of SONGS. Each year, SDG&E proposes an updated 5-year Plan for upgrading existing and building new transmission capacity to the California System Operator (CAISO).

The southern California transmission grid suffers a north-south constraint at a key internal path within Northern California, known as Midway–Los Banos (Path 15) which transfers energy to the major load centers in Northern California. The limits on Path 15 are not expected to significantly change from last summer. In the north to south direction, the transmission limit on Path 15 is 1,275 MWs. In the south to north direction, the transmission limit on Path 15 is 3,950 MWs.

Significant transmission upgrades were implemented in 2000 and 2001 to raise both the SDG&E simultaneous Import Limit to 2,750/2,850 MWs and the non-simultaneous Import Limit (Path 44, South-of-Songs) to 2,200/2,500 MWs. With these higher simultaneous and non-simultaneous import capabilities, adequate imports can be handled during the projected peak for this area.[38]

One new transmission upgrade scheduled for completion by June 2002, is the installation of a new 230/69 kV Transformer Bank at Sycamore Canyon substation. This project is expected to mitigate local SDG&E constraints based on the forecasted load levels.

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[36] For more information on EMF see http://www.niehs.nih.gov/oc/factsheets/emf/emf.htm or http://www.sdge.com/faqs/residential/safety.html

[37] SDG&E paid local generators approximately $40 million under RMR contracts in 2001 to ensure that this generation would be available to meet the reliability needs that could not be satisfied by transmission.

[38] CAISO 2002 Summer Assessment.

As part of it's 5-year plan,[39] SDG&E has proposed building a new transmission line from the Valley Rainbow Substation in Northern San Diego County to the Valley Substation in Riverside County. SDG&E's filing for certification at the CPUC states that the project is needed by 2005 to meet the statewide grid planning reliability criteria established by the CAISO. The CAISO governing board has previously approved the need for Valley Rainbow, or a project like Valley Rainbow. SDG&E believes that the consumers of San Diego will face a risk of outages that is unacceptable by the transmission reliability standards in 2005.[40] A final decision on the project is expected from the CPUC later this year.

4.5.2 Transmission Issues

4.5.2.1 The Valley-Rainbow Interconnect

The $300 million Valley-Rainbow Interconnect Project will provide an interconnection between SDG&E's existing 230-kilovolt (kV) transmission system at the proposed Rainbow Substation on Rainbow Heights Road near the unincorporated community of Rainbow in San Diego County, and Southern California Edison's (SCE) existing 500-kV transmission system, at the Valley Substation on Menifee Road in the unincorporated community of Romoland in Riverside County.[41]

The need for the Project arose out of recognition in the ISO's 1999 transmission planning process that by 2004, SDG&E's import capability would fail to meet the ISO's Grid Planning Criteria. After determining that "all practical 230 kV alternatives of upgrading [SDG&E's] system [had] been exhausted" in its 1999 grid assessment study, SDG&E, in conjunction with the ISO, Southern California Edison ("SCE") and other ISO stakeholders conducted technical studies evaluating wires alternatives on the basis of project reliability, cost effectiveness and construction feasibility.[42] These technical studies included several alternatives for 500 kV lines from SCE's system to the proposed Rainbow Substation site in SDG&E's system and also considered a second Southwest Power Link (SWPL) between SDG&E's system and Arizona. The joint study concluded that a Valley-Rainbow 500-kV line is the "preferred alternative" based on cost, electrical performance, and ease of construction, among other factors.[43] Based on its own consideration of these facts, the ISO Board first approved the Project in May 2000.[44] Since then, the ISO Board has confirmed the need for the Project three additional times, most recently in March 2001.[45]

The project reliability contribution to meet the ISO's criterion that the transmission system be planned to meet projected load with the largest single transmission element and the largest single generator out of service (the "G-1, N-1" criterion).[46] The Project accomplishes this objective by initially increasing the import capability of SDG&E's system by 700 MWs, from 2,500 to 3,200 MWs.[47] While this 700-MW increment in import capability meets SDG&E's immediate reliability needs, the project

[39] Although restructuring of the electricity industry transferred responsibility for ensuring short- and long-term reliability away from electric utilities and regulatory bodies to the Independent System Operator and "various market-based mechanisms" (P.U. Code Section 334), The CAISO's Federal Energy Regulatory Commission (FERC) approved tariff requires that "The ISO or the Participating TO [Transmission Owner], in coordination with the ISO and Market participants, through the coordinated planning processes of the WSCC and the RTGs [regional transmission groups], will identify the need for any transmission additions or upgrades required to ensure system reliability consistent with all Applicable Reliability Criteria."

[40] *Id*., See also, Gen. Acct. Off., Three States Experiences in Adding Generating Capacity, GAO-02-427, May 2, 2002. The Presiding Judge took official notice of this document in her July 10, 2002 ruling.

[41] http://www.cpuc.ca.gov/environment/info/dudek/valleyrainbow/vicinity.jpg

[42] Exh. 100 (at p. 10).

[43] Exh. 100 (at 5/11/00 memo attachment at p. 4).

[44] Specifically, the Valley Rainbow Interconnection Project consists of six major elements: (1) a 500 kV transmission line, (2) a new Rainbow substation, (3) modifications to the Valley substation, (4) an upgrade to the Talega – Escondido 230 kV line, (5) a rebuild of the 69 kV transmission line currently installed on one side of the Talega – Escondido 230 kV transmission line and (6) system voltage support. Exh. 100 (at p. 3). See also Exh. 1 (at pp. II-5 to II-6).

[45] Exh. 100 (at p. 7 and attachment).

[46] In its testimony, the ISO also refers to the G-1, N-1 criterion as the G-1/L-1 criterion. Exh. 101 (at p. 6).

[47] See, e.g., Exh. 1 (at p. II-23).

also provides important going-forward options for further increases in import capacity through future modifications to substations and other upstream and downstream transmission facilities.[48]

In a separate hearing the CEC updated major shortages of capacity during summer peak and the Commission noted that additional transmission would help reduce this risk by increasing the transfer capability into San Diego County by 26 percent from 2,850 to 3,600 MWs and potentially increasing the value of generating assets within the County by giving them access to markets external to the County. Additional hearings are rescheduled this year on the matter.

The cost of the Valley-Rainbow Project, or the annual revenue requirements required to be charged to consumers to support the installation cost of the project, is estimated by multiplying the total installed project cost by the fixed charge rate (currently 17.8 percent). The current installed cost estimate for the project is $341 million. The revenue requirement is $60.7 million and would include an allowance for operation and maintenance.

Over the next 30 years there will likely be major new transmission developments affecting the San Diego region that will involve projects beyond those that are now under consideration. The region needs more transmission access from the North, South and East. An additional 500-MW transmission line through Riverside County, to Devers or Valley, or a second 500-MW line following the right of way of SWPL are possibilities. In addition, private developers have proposed a new direct-current (DC) transmission line connecting Southern California to Wyoming or Utah, thereby creating access to low-cost coal generation. These new DC lines are likely to be costly—$1–2 billion for the entire project including the transmission lines and current conversion equipment. But, they can save a substantial amount of money through potentially lower fuel prices and reliability. There are growing advancements in high-temperature super conducting transmission lines and with DC transmission[49]. DC transmission is very costly considering both the voltage conversion and the cost of the transmission line and right of way. This is why the more conventional DC transmission is limited to distances of more than 400 to 500 miles. DC has the benefits of lower line losses, better control over reactive power and the need for less spinning reserve. The San Diego region could possibly enter into a consortium of interests wanting to build a DC transmission line, if it makes economic sense. The actual markets where DC transmission will be used are very situational and speculative. It is also believed that more super conducting transmission will be used especially in dense markets, Breakthroughs will likely occur over the 30 year study period that will warrant serious consideration of DC and super conducting transmission. The actual economics will have to be evaluated when the right project opportunity is proposed, which is not well defined at the moment.

4.5.2.2 Planning for Transmission

The CAISO “G-1, N-1” Grid Planning Criteria require that the system be capable of meeting projected load under normal conditions with all facilities in service; that is the system should be capable of meeting peak load without resorting to involuntary load curtailments. In addition, CAISO Grid Planning Criteria require that the system be capable of meeting projected load under single contingencies with the largest single transmission element out of service and the largest generating unit out of service.

The critical G-1, N-1 contingency for which SDG&E is required to plan occurs for an outage of the largest generating unit in the SDG&E system (i.e., Encina Unit 5, which is 329 MW), followed by an outage of the most critical transmission line (i.e., the Imperial Valley – Miguel section of the SWPL). Under this condition, the only firm import path left into the service area is the interconnection at SONGS, which has an existing southbound rating of 2,500 MWs. This rating is what is called SDG&E’s non-simultaneous import limit (“NSIL”), which measures the ability to import power into SDG&E’s service area via the 230 kV tie with SCE’s system at SONGS during an outage of the SWPL. As previously discussed, construction of the Valley Rainbow Interconnect Project would initially increase SDG&E’s NSIL by 700 MWs from 2,500 to 3,200 MWs (with further increases possible in the

[48] See, e.g., Exh. 5 (at p. I-6, pp. II-5–II-52), Tr. Vol. 4 (5/6) at pp. 380 (line 4) - 382 (line 5) (SDG&E – Avery) and Exh. 2 (App. A at p. 16 showing ultimate potential buildout of Rainbow Substation).

[49] For a more detailed treatment of the state of DC transmission and the economics of DC transmission see: http://www.abb.com/hvdc.

future). Based on the methodology and criteria described above, SDG&E projects a G-1, N-1 deficiency of 81 MWs in the summer of 2005 rising quickly to 719 MWs in the summer of 2010.

The CAISO has developed a more stringent standard in the San Francisco Greater Bay Area. In the San Francisco Greater Bay Area, the CAISO Grid Planning Standards require that four generating units be removed from service along with the most critical single transmission line in assessing the need for further system upgrades. The more stringent standard for the San Francisco Greater Bay Area is necessary due to the large number of generating units in that area and the higher than normal outage rates of those units. The large number of units in the area increases the probability that at least one unit will be out of service, and in fact, in the San Francisco Greater Bay Area, historically there has been one or more units out of service more than 90 percent of the time.[50]

The addition of Otay Mesa by itself could have the effect of deferring Valley Rainbow for several years (from 2005 to 2009) but only if construction of Otay Mesa (1) did not result in retirements or economic displacements of any existing facilities and (2) if the output of the plant was dispatchable to meet SDG&E's local reliability needs at peak demand.

At one point, the CAISO was considering whether to conduct a competitive solicitation for non-wires alternatives to Valley Rainbow. The CAISO abandoned the idea,[51] in part due to the staff concerns, including:[52]

> *"Pitting generation against transmission challenged the notion of facilitating a competitive market. Staff felt that "While there certainly may be a place for "competition" between generation and transmission projects at a local level…any tangible short-term benefit resulting from a generation project deferring or displacing a larger regional transmission project is likely to be outweighed by the less tangible costs of reduced access and therefore less competition. Moreover, reliance on "market" generation to displace the need for critical regional transmission facilities will inevitably give rise to market power problems and the need to "negotiate" a deal with such generation on a long-term basis." Although a non-wires project could potentially defer or displace the Valley-Rainbow project and result in a lower annual costs to consumers, the total net benefits were unclear. One potentialproject could possibly displace the Valley-Rainbow project, however, it would not increase supply in the San Diego area, because it displaces imports in the area, and would not add to the load serving capability in the area."*[53]

SDG&E also contends that less new generation would be built if the Valley-Rainbow Transmission Interconnect is not built[54] since the economic incentive for generation development will be limited "due to congestion constraints going north from SDG&E."[55] Conversations with Calpine Energy indicate that if and when the Valley Rainbow Transmission Line is built is not a criteria in deciding when to start and complete the construction of the approved Otay Mesa Power Plant. Although the ISO indicated that it had "not undertaken a formal analysis to estimate how likely or significant this impact would be," the ISO further indicated that "it seems reasonable to expect that without adequate transmission infrastructure for exporting power of the San Diego area, some developers will choose not to proceed with proposed new projects in San Diego."[56]

SDG&E's current northbound export capability is 720 MW. This figure is based on the approved WSCC rating of the North of SONGS Path (Path 43) and the current ownership shares in SONGS that

[50] SDG&E Valley Rainbow Testimony, Exh. 101 (at p. 3).
[51] SDG&E Valley Rainbow Testimony, Exh. 100 (at 5/11/00 memo attachment).
[52] SDG&E Valley Rainbow Testimony, Tr. Vol. 8 (5/10) at p. 910 (lines 16-23) (ISO – Miller): "after we started seeing what was happening with the markets in California and the reliability concerns in California, we decided that for major paths like this it was not appropriate to substitute generation for the transmission. So the ISO board decided not to conduct a competitive solicitation . . . there may have been other rationales among the board members as well, but that's as much as I'm aware of."
[53] Exh. 100 (at 7/25/2000 memo attachment at p. 2).
[54] SDG&E Valley Rainbow Testimony, Exh. 100 (at p. II-14).
[55] SDG&E Valley Rainbow Testimony,
[56] SDG&E Valley Rainbow Testimony, *Id*.

are delivered northward over Path 43. Construction of the Interconnect Project would more than double the existing northbound capability. This would translate into an additional 750 to 1,000 MWs of generation resources that could be exported from SDG&E and northern Mexico to meet California's statewide resource requirements and enhance the regional and statewide grid. This increase in export capability would increase the net resources available to meet statewide resource requirements and reserve margins.[57] Without Valley Rainbow, the generation development in these areas may for all practical purposes be limited to about 1,000 to 1,400 MWs due to congestion constraints going north from SDG&E.[58]

An outage of the single interconnection at SONGS can leave SDG&E with a serious power shortage, such as that which occurred on February 27, 2002. If the Valley Rainbow Interconnect Project had been in operation at the time of this event, it would have prevented the need for firm load shedding of some 211,000 customers (approximately 300 MW) in SDG&E's service area.[59]

The CAISO conducted a preliminary study of various alternative long-term transmission grid expansion concepts and evaluated how effectively each could mitigate this risk. All of the alternative expansion concepts assessed by the ISO for purposes of mitigating the risk of voltage collapse and line overloads included a Valley-Rainbow 500 kV line as a common building block. Even if other transmission reinforcements in the CAISO's June 2000 report are not built, Valley Rainbow includes more than 1,100 megavar ("MVAR") of voltage support apparatus that would significantly mitigate reliability risks in the Southern California grid in the absence of SONGS generator capacity by enhancing regional voltage stability.[60]

How the nation, state and region approach transmission planning needs to be totally rethought and redesigned. A priority area of endeavor by FERC is to use existing and new transmission infrastructure—through the management of large Regional Transmission Organizations (RTOs) to support the market function. Inadequate transmission capacity into an area results in potentially higher locally capacity prices, market power, increased unreliability and a need for voltage support. Additional transmission may also help diversify the fuel mix of future power supply.

Current transmission planning can be improved. While yearly 5-year transmission plans are completed by SDG&E, they do tend to react to the location of planned generation. In turn, new plants are likely to be located near sufficient transmission. A planning of "convenience" occurs. This type of planning does not sometimes focus on what is best for markets, networks, and reliability. This is why FERC proposed rules and RMR units are used – to make up for gaps or resulting problems regarding network integrity in the future. A broader set of issues and concerns will be considered.

What is needed is an advanced transmission planning study that looks at the county as a whole and attempts to optimize the location of new generation, distributed generation and other resources and also suggest which areas to target for improvement for the local network. New forms of optimization models are being created that improve load profiles for generation and demand side equipment. This should be done over the next two years, as issues regarding new plants and the need for new transmission projects get resolved. SDG&E and SDREO should consider jointly completing the study.

Over the next 30 years additional technological improvements in transmission operation and control are likely to occur. There may a greater use of direct-current lines or the use of advanced technologies like high-temperature superconductors to improve current flow. In addition, there is also a growing role of merchant transmission investments.[61] FERC and U.S. DOE are interested in merchant transmission because it can introduce competition into what historically has been viewed as a natural monopoly.

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[57] See generally Exh. 1 (at pp. II-10, II-11 and pp. II-20 to II-23) (as modified by Exh. 4) and Exh. 3 (e.g., Table 1).
[58] Exh. 4 (at p. II-30).
[59] Exh. 5 (at p. II-20).
[60] CAISO, "San Onofre Nuclear Generating Station Operational Study – Phase 2 Report Transmission Plan of Service" (June 12, 2000).
[61] Merchant transmission lines are built by investors and recover costs in the market, rather than through regulated transmission rates.

4.6 Other Issues Affecting Electricity Supply

There are additional regulatory and legislative issues that will impact the need for traditional grid-based power supply.

4.6.1 Effects of State Executive, Legislative, Regulatory and Policy Decisions

There are a number of ongoing federal, state policy and regulatory proceedings that will have an impact on the availability and price of electricity. On the electric side, the state needs to reach a consensus on the future market model—will the state continue to rely on market-based, competitive markets, or will the state move back to traditional cost-based, regulated markets. Utility ownership of generation assets, including distributed generation is also under consideration.

In addition, California needs to reach consensus on how to address regional transmission congestion and define the appropriate level of reserves beyond the required seven percent reserves to create stable electric prices. A more integrated approach is needed on plant siting and new transmission planning for both the California Independent System Operator (CAISO) and the Western States Coordinating Council. California drives much of the Western regional electric demand, but the probable and more attractive supply opportunities are in other WSCC states, which may provide more viable locations for new plant development although impending transmission constraints into the region have to also be considered. These factors affect local prices and reliability and hence, why a robust regional energy plan is necessary.

There are also local tariff constraints that inhibit local wheeling of distributed generation that also needs to be evaluated in light of the region's need for additional generating capacity in the region. Additional local generating supply in the county is possible if tariff provisions were to be modified. For example, the City of San Diego and the San Diego County Water Authority could potentially provide 50 MWs or more of generation through a combination of renewable and distributed generation resources that already exist or are being currently considered for development to meet internal needs. Other public and private entities, including several of the larger commercial and industrial firms as well as the military could potentially contribute significant generation resources to meet the need of external users if wheeling restrictions were modified or removed and if the business case could be justified.

Perhaps one of the biggest issues facing the state of California is the structure of the future market. Currently retail choice for CAISO-served customers have been eliminated with a few grand-fathered exceptions. In addition, the state legislature is starting to investigate new market models. It may take 2 to 3 years before consensus is reached on what the new market model should consist of. One important consideration for San Diego County is to encourage a large regional WSCC based wholesale market that offers day-ahead trades and also the possibility for bi-lateral power supply options. Local state utilities should be allowed to have generation assets for meeting local retail loads (even though functional separation would likely exist). The state needs to dramatically build its reserve margins up to 15 percent while carefully monitoring available import supplies of the surrounding states that make up the WECC. The 15 percent is not a mandatory reserve, but a commonly accepted estimate for minimum reserves for reliability and price stability.

Sufficient margins are important because in the electric utility business, there is little ability to store the commodity to be used when it is needed. Therefore high cost assets (generators) need to exist in order to provide the power at the time of peak usage. Consumers need to pay "rent" in order to have these assets available when they are needed. In the spot power market, this "rent" is paid via a "scarcity premium" that gets added to incremental costs when marketers price the output of their facilities.[62] These bid adders or scarcity premiums can be quite large. During 2000, generators could price electricity at levels that were low enough not to cause voluntarily curtailment. Generators contend that they need to capture these high "scarcity premiums" when conditions allow them to do so in order to cover the many times during the lifetime of these assets when supply/demand is such that competition will result in very little (if any) "scarcity premium" in the pricing of the commodity.[63]

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[62] Exh. 1, Ch. IV (at p. 3-2).
[63] Id. (at pp. 3-2 to 3-3).

Critical regulatory and legislative issues that the region should closely monitor include:

- Whether or not California will adopt locational[64] or zonal pricing to reflect regional transmission constraints;
- The role and impact of the California Power Authority and what it can do to help the City and County of San Diego leverage resources to implement the energy strategy;
- Future relationship of municipal generation assets and dispatch to CAISO power—this additional power to the market could help moderate prices;
- Potential joint investment action of municipals and authorities with private plant developers
- New legislation regarding the role of IOUs in purchasing power and renewable portfolio standards[65] This may provide the region an opportunity to provide these additional renewable resource local.

4.6.2 Federal Initiatives

FERC Order 888 and recently affirmed by the U.S. Supreme Court gave FERC plenary authority over interstate transmission. In addition, the Supreme Court encouraged FERC to specify in more detail provisions in which it would investigate and correct bundled retail transmission discrimination. FERC has jurisdiction over retail bundled transmission where it believes some forms of discrimination exist. In addition, Order 888 ordered functional unbundling of generation and transmission costs. Also, in a separate working paper by FERC, "A Vision of the Future," FERC endorsed the single tariff model for transmission and avoided the current practice of inflating transmission tariffs due to a "pancaking[66]" of tariffs over different transmission lines.[67] Order 888 also led to the creation of ISOs. However, this was a voluntary and extremely time-consuming process that was not progressing as much as FERC would like. This led to Order 2000.

FERC Order 2000 calls for the formation of large RTOs to coordinate markets and ensure the reliability of the nation's transmission system. Regional characteristics of RTOs must demonstrate:

- Management independence of market participants
- The scope of RTO functions must be broad to sufficiently carry out their operations
- Each RTO must coordinate the security for the region and have excluding authority for maintaining short-term reliability of the grid it operates.

Future RTOs are expected to perform eight important functions:

1. Tariff administration and design
2. Congestion management
3. Parallel path flow
4. Ancillary services
5. Open Access Same Time Information System Administration (OASIS)
6. Market monitoring
7. Planning and expansion, and
8. Interregional Coordination.

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[64] LMP pricing is a type of zonal or nodal pricing that charges variable fees based on day ahead and real time markets for power on a day ahead basis. Key cost components are the marginal nodal prices for the next increment of load at a given time (based on demand bids or supply offers), congestion and losses. For a more detailed discussion of LMP pricing, see: http://wwwsmd.iso-ne.com/cmsmss/Standard_Market_Design/Frequently_Asked_Questions/Locational_Marginal_Pricing.Html#q80. Also see: http://www.pjm.com/lmp/tdocs1/control_page.html. Application of this type of pricing varies by RTO/ISO. The California is going to a form of locational or nodal pricing. FERC in the new market design wants to see more LMP pricing like PJM uses. It would be prudent for power system planners in California to assume that this form of congestion management and pricing will occur in the future.

[65] SB 530 (Sher) would require utilities to increase the amount of renewables in their purchased power mix by one percent per year to achieve 20 percent renewables by 2015.

[66] Pancaking refers to the layering of transmission costs of various transmission system owners.

[67] FERC December 2001.

FERC in 2001 began to use existing rules to implement this order. RTOs are expected to improve efficiency of grid operations and management, leading to a savings of from $1 to 10 billion annually.

At the Federal level there are a number of proceedings, past and future, that will have an impact on regional power supply. FERC is interested in its continued management of interstate wholesale electricity transactions. FERC also has responsibility for creating a standard regional market design. FERC also oversees the CAISO and will likely more closely observe its behavior in the implementation of the standard market design that will be released at the end of June 2002. FERC also has an interest in removing regional transmission congestion, improving regional transmission monitoring and control, and monitoring more closely market power and trading practices that may drive up wholesale power prices. FERC is also addressing the issue of siting and permitting new transmission right of way. Transmission costs less than 10 percent of the delivered price of electricity. It is also estimated that transmission saves consumers about $13 billion annually.[68] In late July 2002, the standard market design was released and comments have been extended. The principle benefits of the "SMD" to San Diego County are more systemic and timely siting of transmission lines in adjacent states and more common market rules. Also, postage-stamp transmission pricing would be used vs. the current "pancake" pricing in the WSCC. This adds costs and restricts market dynamics.

Another key Federal activity for the Western states was the creation of Price Caps to control the extreme price volatility in the Western power markets. FERC Price Caps which set a ceiling of $90 per MWh for wholesale electricity sold through the CAISO will be increased to $250 in October 2002. This may lead to price stability and also help create additional value for demand reduction programs.

4.6.3 Local Initiatives

Perhaps one of the most significant initiatives is to issue local bonding to support the development of major new generation and transmission facilities. In addition, the County Water Authority, San Diego Port District and other municipalities can potentially expand their power development activities and organize major conservation and group renewable initiatives with other community organizations.

In addition, SDREO working with SANDAG and other public and private interests can spearhead a major conservation, distributed generation and renewable initiatives. Already SDREO has obtained more than $30 million to spearhead load monitoring, DG, and photovoltaic initiatives. The future over the next 30 years will require an eight-fold increase in combined conservation, demand response and distributed generation initiatives beyond what the market has already seen. These and other demand-side programs will be discussed in more detail in Chapter 5.

[68] U.S. DOE, National Transmission Grid Study (May 2002) p. xi.